

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION)
OF IDAHO POWER COMPANY FOR)
AUTHORITY TO INCREASE ITS RATES) CASE NO. IPC-E-03-
13
AND CHARGES FOR ELECTRIC SERVICE)
TO ELECTRIC CUSTOMERS IN THE STATE)
OF IDAHO.)
_____)

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

J. LAMONT KEEN

1 Q. Please state your name and business address.

2 A. My name is J. LaMont Keen and my business
3 address is 1221 West Idaho Street, Boise, Idaho 83702.

4 Q. What is your position at Idaho Power
5 Company?

6 A. I am the President and Chief Operating
7 Officer.

8 Q. What is your educational background?

9 A. I graduated magna cum laude in 1974 from the
10 College of Idaho in Caldwell, Idaho now called Albertson
11 College of Idaho, receiving a Bachelor of Business
12 Administration Degree in Accounting. In 1994 I completed
13 the Advanced Management Program at the Harvard University
14 Graduate School of Business. I have also attended many
15 utility management-training programs, including the Stone &
16 Webster Utility Management Development Program, the
17 University of Idaho Public Utilities Executive's Course and
18 the Edison Electric Institute Executive Leadership Program.

19 Q. Please outline your business experience.

20 A. I have worked in the electric utility
21 industry at Idaho Power Company for nearly 30 years,
22 beginning my employment in 1974 in the accounting

1 department. I advanced through several accounting, analyst
2 and management positions and in July 1988, I was promoted
3 to Controller. In November 1991 I was appointed to Vice
4 President of Finance and Chief Financial Officer and served
5 in that capacity until March of 1999 when I was also given
6 responsibility for all of the administrative areas of the
7 Company as Senior Vice President of Administration and
8 Chief Financial Officer. In March of 2002, I was appointed
9 President and Chief Operating Officer where I have
10 responsibility for the Company's operating units. I either
11 have or have had responsibility for virtually all aspects
12 of the Company's operations at some point in my career.

13 Q. What are your duties as President and Chief
14 Operating Officer of Idaho Power Company?

15 A. I am responsible for the general oversight
16 of all the utility operations including all power supply
17 and delivery activities.

18 Q. What is the purpose of your testimony?

19 A. As Idaho Power Company's president, I am
20 testifying as to policy matters related to the Company's
21 filing of this request for general rate relief.
22 Specifically, I will address the events and circumstances

1 that led to this rate application, including an overview of
2 significant events, both regulatory and otherwise, that
3 have occurred over the last decade; the impact of ten years
4 of growth on our utility system; the Company's stewardship
5 of the system during the recent difficult period; the
6 increasing emphasis on system reliability; the critical
7 demand for investments in infrastructure; and the cash flow
8 and earnings implications to the Company of managing
9 through all of the above.

10 Q. Please describe the Company's last general
11 rate increase in Idaho.

12 A. The Company's last general rate case, Case
13 No. IPC-E-94-5, concluded on January 1, 1995 when the Idaho
14 Public Utilities Commission (IPUC or the Commission) issued
15 Order No. 25880 authorizing Idaho Power to increase its
16 rates by \$17,177,048 or 4.19 percent. In that case, the
17 rate of return on common equity was established at 11
18 percent with an overall rate of return at 9.199 percent.
19 Permanent rate changes were implemented on February 1,
20 1995.

21 Shortly following the conclusion of Case No. IPC-E-
22 94-5, the Company completed its upgrade of the Twin Falls

1 benefit of its Idaho customers. The stipulation also
2 provided that Base Rates would not change prior to January
3 1, 2000. Because of improved operating conditions,
4 including hydro availability, the Company never had to use
5 ADITC to supplement earnings during the moratorium. On the
6 other hand, Idaho Power's customers were able to experience
7 the benefits of revenue sharing during the years 1996,
8 1997, 1998, and 1999. The total benefit shared with the
9 Idaho retail customers was approximately \$28 million.

10 Q. Has the corporate structure changed at Idaho
11 Power during the last ten years?

12 A. Yes. On October 1, 1998, with the formation
13 of IDACORP, Inc., the Company became a part of a holding
14 company structure. IDACORP, Inc. serves as the parent of
15 Idaho Power Company, a regulated utility, as well as a
16 number of unregulated subsidiaries. The purpose in forming
17 IDACORP, Inc. was two-fold. First, the structure allowed
18 Idaho Power to continue as a regulated utility just as it
19 had for the past 82 years. At the same time, the creation
20 of a holding company enabled present and future non-
21 regulated business units to compete for business in the
22 non-regulated arena without saddling the regulated utility

1 with the capital requirements and risks of those ventures.

2 The move to a holding company structure followed
3 approval by multiple regulators including the Idaho
4 Commission in Order No. 27348 issued on January 29, 1998 in
5 Case No. IPC-E-97-11.

6 Q. Following the rate moratorium, what impact
7 did the Western energy crisis have on Idaho Power?

8 A. By the summer of 2001, the West was in the
9 grip of the nation's worst energy crisis.

10 Increases in the price for natural gas, an
11 increasingly important fuel for thermal generation of
12 electricity in California, combined with the 2000-2001
13 water conditions that were among the lowest ever recorded
14 in the Pacific Northwest region according to the U.S.
15 Department of Agriculture, created further upward pressure
16 on wholesale prices emanating from the California market.
17 Compared with the first quarter 2000, wholesale power
18 prices for 2001 peak period transactions in the Pacific
19 Northwest rose by almost a factor of ten, from an average
20 of \$25 per megawatt-hour to \$240 per megawatt-hour as
21 measured by the Dow-Jones Mid-Columbia Index. Price spikes
22 took place on the hourly spot market that resulted in the

1 price of electricity exceeding \$1000 for short periods of
2 time.

3 Idaho Power's operations were also adversely
4 affected by the tremendous increase in prices for purchased
5 power, increased demand, and reduced hydroelectric
6 generation. This particular combination of economic and
7 natural phenomena produced substantial increases in costs
8 to supply power to customers not only in Idaho Power's
9 service territory but also across the west. Large and
10 small utilities throughout the west were filing for double
11 digit rate increases on multiple occasions during the 18-
12 month energy crisis. Idaho Power was no exception as its
13 annual PCA rate applications increased to record amounts.

14 Q. Please describe the severity of the current
15 Idaho drought.

16 A. Drought is of particular concern to a hydro-
17 based utility. Reductions in the region's already limited
18 water supply for extended periods of time can produce
19 devastating impacts in terms of reduced hydro-generation
20 availability and correlating higher energy costs. Drought
21 is also a "creeping phenomenon" making its onset and end
22 difficult to determine. The effects of drought accumulate

1 slowly over a considerable period of time and may linger
2 for years after the termination of the event. Current
3 water supply conditions for Idaho demonstrate the reality
4 of this phenomenon.

5 At its peak, the 2000 drought was as severe as any
6 of the major droughts of the last 40 years as measured by
7 temperature and moisture. This exceptionally dry summer
8 resulted in low soil moisture entering into the winter.
9 Precipitation was much below normal over most of the
10 Pacific Northwest during the fall and winter of 2000-2001
11 and hydrologically, the evolving 2001 drought appeared to
12 be similar in magnitude to the 1977 drought of record based
13 on streamflow and reservoir levels.

14 In 2001, the water supply outlook for the state of
15 Idaho remained much below normal and continued to be one of
16 the lowest years on record. May 2001 runoff was estimated
17 to be the second or third lowest on record for many sites
18 across the state. Snowpack for the same period remained
19 low at 30 to 55 percent of average across Idaho. The
20 severity of the 2001 drought was further exacerbated by the
21 ongoing California power problems, one result of which was
22 that the Federal System reservoirs were drafted to some of

1 their lowest levels ever.

2 In 2002 and 2003, the entire Columbia River Basin
3 experienced drought conditions. The Columbia River at The
4 Dalles, Oregon, is a commonly used reference point to gauge
5 flows in the Columbia River in the Pacific Northwest. In
6 2002 and 2003, the April through August flows at The Dalles
7 averaged only 68 percent of average. These low flows
8 significantly reduced the amount of surplus energy
9 available for the Company to purchase.

10 In 2003, the creeping drought phenomenon continues.
11 Over the past four years, the April through July inflow to
12 Brownlee Reservoir has averaged about 60 percent of the
13 1960 through 2003 average. Even more telling, in southern
14 Idaho the April through July flows at Swan Falls Dam have
15 declined to 46 percent of average. In July 2003, the flow
16 at Swan Falls Dam was at the lowest level recorded by
17 either the USGS or Idaho Power. In response to these low
18 flows, the Idaho Department of Water Resources was prepared
19 to take the extreme measure of actually curtailing junior
20 upstream surface water diversions.

21 Q. What effect does a severe drought have on
22 the Company?

1 A. During drought, Idaho Power must rely more
2 heavily on purchased power to meet system loads, usually at
3 higher market prices due to supply scarcity. At the same
4 time, there are obviously less "surpluses" to sell to
5 offset increased market purchases. The result is upward
6 pressure on the Company's power supply costs.

7 Q. How did the combination of drought and high
8 market prices impact the Company's PCA requests?

9 A. Because Idaho Power relies predominantly
10 upon hydroelectric generation to serve its load, the
11 Company's actual costs of providing electricity can vary
12 dramatically from year to year depending on changes in
13 streamflow and market prices. In recognition of the
14 fluctuating power supply costs associated with variable
15 hydroelectric generation, the Commission approved a "Power
16 Cost Adjustment" (PCA) mechanism for Idaho Power in 1993.
17 During the years that the PCA has been in effect, there
18 have been both annual credits and surcharges. However, as
19 a result of the Western energy crisis and drought
20 conditions, the Company's PCA application in 2001 was the
21 largest amount ever requested. Following extended
22 hearings, the Commission authorized the bulk of the \$227.4

1 million requested under the PCA mechanism. The following
2 year the Company's PCA filing was even greater. The issues
3 were complex and required a careful balance between public
4 policy concerns and the need to achieve just, fair and
5 reasonable rates for recovering excess power costs. As it
6 did in 2001, the Commission disallowed a portion of the
7 jurisdictional power supply-related costs contained in the
8 2002 PCA filing.

9 Q. How did the Company view these PCA orders?

10 A. Although the Company was concerned to see
11 disallowances emerge in the PCA, it generally viewed both
12 the 2001 and 2002 Commission decisions as a signal that the
13 Company was operating within the guidelines established by
14 the IPUC and consistent with ratemaking concepts of the
15 PCA. The decisions also lent valuable support to the
16 Company during deteriorating financial circumstances.

17 Q. Please describe Idaho Power's most recent
18 PCA filing.

19 A. During the 2002-2003 PCA period, wholesale
20 energy prices had returned to pre-energy crisis levels.
21 However, Idaho Power continued to be impacted by diminished
22 precipitation levels and the resultant reduction in

1 hydroelectric generation. On April 14, 2003, the Company
2 filed a request to implement its annual PCA that would
3 reduce overall rates by over 18 percent. On May 13, 2003,
4 the Commission approved the Company's application. Despite
5 the decrease, rate levels are still more than \$80 million
6 above Base Rate levels. With more normal snow pack and
7 current prices, another PCA decrease could occur next
8 spring.

9 Q. You previously discussed the impact of the
10 Western energy crisis on the Company. Now, please
11 elaborate on the Western energy crisis's impact on the
12 Company's PCA.

13 A. When the PCA was first developed in 1992 and
14 implemented in 1993, no one anticipated the types of market
15 prices and volatility that occurred in 2000 and 2001.

16 At its inception, based on historical data, the
17 anticipated power supply expense volatility was
18 approximately \$116 million from best to worst condition.
19 During the western energy crisis, Idaho Power's power
20 supply expenses were \$204 million over those in Base Rates
21 in 2001 and \$337 million over base in 2002. The two years
22 in combination were \$541 million above base with the

1 Company's shareholders absorbing over \$127 million of that
2 total amount. As a result, Idaho Power's customers and
3 shareholders both bore substantial power supply costs that
4 were of a magnitude not contemplated at the PCA's
5 inception. The shareholders burden came from both the
6 sharing mechanism and from disallowances in the 2001 and
7 2002 PCA orders.

8 Q. What is your impression of the PCA?

9 A. I believe that the PCA is a fair ratemaking
10 mechanism that has recently been stress-tested under
11 extreme conditions. Two of the attributes that have helped
12 the mechanism stand the test of time are the true up and
13 the sharing provision. The true up provides a means for
14 actual costs to be ultimately accounted for and included.
15 The sharing provision ensures that the interests of both
16 the Company and its customers are aligned on each
17 transaction.

18 Q. Since your Company has received significant
19 cost recovery through the PCA in recent years, why do you
20 need to file a general rate application?

21 A. The PCA only addresses the portion of the
22 Company's total annual revenue requirement that corresponds

1 to the variable cost of supplying energy to Idaho retail
2 customers. The power supply expenses that flow through the
3 PCA are normally limited to fuel for thermal plant
4 operations and purchased power. The PCA mechanism also
5 subtracts surplus sales revenues from these expenses. The
6 sheer magnitude of the power supply expenses in recent
7 years placed their ratemaking treatment at a higher
8 regulatory priority than the pursuit of general rate
9 relief. The Company not only had to prioritize its
10 requests before the Commission, but recognize rate impacts
11 to customers as well. Accordingly, the Company chose to
12 postpone filing for general rate relief. Now in 2003, with
13 the PCA component of our rates beginning to drop, other
14 increasing expenses and new investments need to be brought
15 before the Commission for inclusion in Base Rates.

16 Q. How has the Company's investment in electric
17 plant grown since the last general rate case?

18 A. Since 1993, the test year for the last
19 general rate case, the Company's investment in electric
20 plant has grown by \$856 million from nearly \$2.32 billion
21 to slightly over \$3.17 billion. The \$856 million
22 represents a 10-year 37 percent increase in Company

1 investment in electric plant on behalf of our customers.
2 Put in annual terms, Company investment in electric plant
3 has grown at about 3.2 percent per year since the last
4 general rate case.

5 Q. Of the \$856 million of additional investment
6 in electric plant, please detail the growth in investment
7 for generation, transmission, and distribution facilities.

8 A. In the last ten years, the Company has
9 invested \$156 million for generation additions and
10 upgrades. The most recent generation plant addition was
11 the Danskin gas-fired generation plant located in Mountain
12 Home. The investment in the Danskin generation facility
13 was approximately \$50 million. In the same period of time
14 the Company has invested \$198 million toward the
15 construction of transmission facilities and \$366 million
16 toward the construction of distribution facilities. The
17 most recent investment in transmission facilities included
18 in this application is the \$19.4 million Brownlee-Oxbow 230
19 kV transmission upgrade. The remaining \$136 million of
20 investment growth is attributable to general and other
21 plant items.

22 Q. Please describe the growth in Company

1 expenses associated with operating and maintaining a \$3.2
2 billion system.

3 A. The expenses associated with operating and
4 maintaining a \$3.2 billion system today have grown to about
5 \$540 million per year from the \$412 million needed to
6 operate and maintain a \$2.3 billion system in 1994. The
7 \$128 million growth in expenses represents a 31 percent
8 increase in expenses from levels established 10 years ago.
9 Put in annual terms, Company expenses have grown at about
10 2.7 percent per year since 1993.

11 Q. Please describe the growth in Company
12 revenues over the same 10-year period of time.

13 A. Since the last general rate case, Company
14 test year operating revenues have grown only 13 percent
15 compared to the 37 percent growth in investment and the 31
16 percent growth in expenses. Clearly, growth has not paid
17 for itself. The incremental costs of adding, operating and
18 maintaining generation, transmission and distribution plant
19 are greater than the embedded costs associated with
20 generation, transmission and distribution plant that have
21 been the basis of Company rates over the last ten years.

22 Q. How has Idaho Power managed through this

1 growth?

2 A. While both inflation and customer growth
3 impact our expense level, the Company has actually been
4 able to keep expenses well below the combined growth rate
5 of inflation plus customer growth. I have had Exhibit No.
6 1 prepared to demonstrate these relationships over time.
7 Exhibit No. 1 tracks the actual operating and maintenance
8 (O&M) expenses from 1993 through 2002 and includes the 2003
9 O&M expenses that are part of the Company's general rate
10 request. Exhibit No. 1 also tracks the 1993 O&M expenses
11 over the same time period escalated by the combined impacts
12 of inflation and customer growth.

13 Q. What is the current condition of Idaho
14 Power's distribution system?

15 A. The system has been expanded to absorb the
16 growth of the past decade. As noted before, over 40
17 percent of the Company's investment during this period has
18 gone into the distribution system, yet many of the
19 Company's distribution stations and lines are at or near
20 capacity. During this time, we have worked diligently to
21 improve operating efficiencies and utilization. However,
22 there is little room to withstand additional growth without

1 new construction.

2 Q. Please describe the operating capacity
3 situation with the Company's distribution feeders.

4 A, The utilization of assets, or loading levels
5 on feeders, has increased significantly. The peak load per
6 distribution feeder in 1987 averaged 4.9 megawatts. Today,
7 this has increased to 7.0 megawatts. Approximately one
8 half of the retail load is served by feeders operating near
9 their full capacity at peak load.

10 The Company has carefully prioritized and scheduled
11 the construction of new facilities while relying heavily on
12 our experienced workforce to manage and operate the system
13 with these reduced margins.

14 Q. How is the Company managing new growth on
15 its distribution system?

16 A. The Company has continued to manage
17 substations and feeder loadings to meet growth through
18 selective distribution capacity increases and the use of
19 better load data acquisition systems. This has allowed the
20 Company to utilize much of the reserve capacity once
21 available. However, further reductions in reserve capacity
22 would likely reduce reliability and service quality to our

1 customers. Consequently, additional growth will require
2 new facilities be added to the system at full marginal
3 cost, rather than being able to leverage existing capacity
4 in the system at the old embedded cost. The Company has
5 identified over \$400 million in growth-related sub-
6 transmission, substation, and distribution infrastructure
7 additions required prior to 2010. This does not include
8 the ongoing costs of maintaining or replacing existing
9 facilities.

10 Q. Since the last rate case, has Idaho Power
11 Company invested in 230 kilovolt and above transmission
12 facilities?

13 A. Yes. Contrary to reports of other utilities
14 not investing in transmission infrastructure, Idaho Power
15 has invested in backbone transmission facilities both to
16 serve load and to improve service reliability. Since 1996,
17 Idaho Power peak load has grown 526 megawatts. As a part
18 of an over-all strategy to meet this load growth, the
19 Company has undertaken several backbone transmission
20 projects:

| | | |
|----|--|---------|
| 21 | Brownlee-Ontario-Caldwell 230 kV Project | \$30.5M |
| 22 | Boise Bench-Locust 230 kV | \$ 5.7M |

1 growth and where resource additions are developed.

2 Q. What are the transmission implications for
3 the next ten years?

4 A. A significant portion of the Company's load
5 growth is occurring in Ada and Canyon counties. The next
6 ten years will require continuing transmission system
7 facility improvements in this area.

8 Toward the end of this time horizon, the existing
9 bulk transmission system serving the Treasure Valley area
10 (Ontario to Mountain Home) will reach its maximum present
11 capabilities and major transmission additions from the
12 Northwest and/or areas east of Midpoint may become
13 necessary.

14 Q. Based on recent experience, how will the
15 cost of these new transmission facilities compare to
16 previous transmission construction costs?

17 A. These future backbone expenditures will
18 likely cost twice the previous expenditures for a
19 comparable amount of load growth, about \$400 per kilowatt
20 or on average \$20 million per year.

21 Q. What resource scenario was used in deriving
22 these cost estimates?

1 planning philosophy includes reducing market dependence and
2 building resources as required under the 2002 Integrated
3 Resource Plan (IRP). During the 2002 IRP process, public
4 input supported this planning philosophy which is based
5 upon more stringent criteria for both loads and resources.

6 Q. How does this new generation resource
7 planning philosophy impact costs?

8 A. By using a less than median water planning
9 criteria the need for additional resources will be
10 accelerated. This applies to both peaking as well as base
11 load facilities.

12 Q. Please describe the Company's current
13 generating resources strategy.

14 A. Idaho Power will have to acquire a variety
15 of resources throughout the coming years to meet its
16 growing load requirement. The Company has recently
17 notified Mountain View Power (MVP) that it is the
18 successful bidder in the Company's most recent Request for
19 Proposal for a generating resource. Once completed, MVP
20 will transfer the plant to Idaho Power ownership. Idaho
21 Power has decided to name this plant the Bennett Mountain
22 Power Plant. The Bennett Mountain Power Plant will provide

1 approximately 160 MW of peaking capacity. The Bennett
2 Mountain Power Plant project will satisfy a portion of a
3 portfolio of resources to be acquired to meet the 2002 IRP
4 objectives. The Company has filed with the Idaho
5 Commission for a Certificate of Convenience and Necessity
6 for the Bennett Mountain Power Plant. In its application,
7 Idaho Power has provided a commitment estimate of \$54
8 million for the generation portion of the project, which is
9 scheduled for completion in April 2005.

10 The results of the 2004 IRP will likely show
11 additional resource needs in the near future.

12 Q. What is the current condition of the
13 Company's jointly owned coal-fired resources?

14 A. As the demand for electricity has grown and
15 the drought continues, we have relied heavily on our
16 jointly owned coal-fired resources. These facilities were
17 constructed in the 1970s through the early 1980s. As they
18 age, they are in constant need of upgrading and
19 rehabilitation. New environmental regulations have also
20 added capital and maintenance requirements. We anticipate
21 increased capital and O&M costs for these facilities in
22 order to keep them reliable and compliant.

1 Complex is the largest of Idaho Power's 17 hydroelectric
2 projects on the Snake River. Currently, over 420,000
3 customers rely on this complex for power as it produces
4 nearly two-thirds of the hydroelectric generation and 40%
5 of the total generation of the Company in an average water
6 year. The final relicensing application consisted of
7 36,000-pages and was the culmination of nearly a decade of
8 studies conducted by the company, focused on fish,
9 wildlife, plants, water quality, recreation and cultural
10 resources. Idaho Power conducted over 100 studies and
11 ultimately the application process cost Idaho Power more
12 than \$50 million. The application also includes \$324
13 million worth of new and continuing mitigation efforts to
14 offset present and future environmental impacts resulting
15 from the operation of the facility. These mitigation
16 efforts, referred to as protection, mitigation, and
17 enhancement (PM&E) measures include Water Use and Quality,
18 Fish and Mollusc Resources, Wildlife Resources, Botanical
19 Resources, Cultural Resources, Aesthetic Resources and
20 Recreation Resources.

21 As the Relicensing Tasks Flow Chart shows, the
22 Company began work on the Hells Canyon relicensing effort

1 in early 1993. In September 2002 Idaho Power submitted a
2 25,000-page draft license application to the FERC and
3 hundreds of stakeholders who constituted the Collaborative
4 Team. The Company accepted over 4,500 written comments on
5 its draft application through January 2003. Comments from
6 the different respondents were addressed and included in
7 the final new license application filed in July 2003. The
8 FERC is planning to begin their National Environmental
9 Protection Act process for the Hells Canyon project, with
10 scoping meetings scheduled for the third week of November
11 2003 followed by requests for additional information in
12 December 2003. The Company expects to incur consultation
13 and compliance costs through 2008 followed by actual
14 Article Compliance costs (once the FERC has issued a new
15 license) that will continue well on in to the next decade.
16 Exhibit No. 3 charts the Hells Canyon relicensing expenses
17 incurred to date and the expected costs through 2010 at
18 which time the Company will have spent approximately \$100
19 million.

20 Q. What is the financial condition of Idaho
21 Power Company?

22 A. The current financial situation has

1 developed over a period of years. In 1999, the Company's
2 short-term debt was \$20 million, internal cash generation
3 was at 114 percent, and we were experiencing sales growth
4 in our service area.

5 In 2000, the combination of drought and energy
6 crisis that I spoke of earlier built up a huge PCA deferral
7 and caused us to file our annual PCA earlier than usual.
8 As described previously, the IPUC ultimately approved most
9 of the 2000-2001 PCA in two parts -- \$168 million in May of
10 2001 and another \$59 million in October of 2001. PCA
11 disallowances of \$11 million were written off in October of
12 2001. During 2000, capital expenditures increased to \$132
13 million, while short-term debt rose to almost \$60 million
14 and internal cash generation fell to 42 percent.

15 By 2001 Idaho Power Company's regulated earnings per
16 share had dropped to \$.60 per share. 2001 was
17 characterized by industry turmoil and continued Idaho
18 drought. The "Perfect Storm" occurred with the combination
19 of high market prices, lower-than-average stream flows, and
20 higher demand. The PCA deferrals again grew, this time
21 from the combined effects of the load reduction programs
22 for the Astaris Special Contract and the irrigation

1 customers. The un-recovered portion of the PCA costs
2 absorbed by shareholders reached \$76 million. Operating
3 cash flow for Idaho Power was a negative \$59.6 million.
4 The short-term debt balance skyrocketed to \$282 million.
5 2001 construction costs increased to \$157 million,
6 including \$49 million for the Danskin Power Plant. Net
7 working capital declined from 2000 to 2001 by \$156 million.
8 Utility operating income was also down from 2000 to 2001 by
9 \$79 million primarily due to the PCA absorption.

10 Idaho Power's earnings in 2002 were \$2.24 per share,
11 but these were heavily supported by a one-time \$.92 income
12 benefit related to a tax method change. Without it, the
13 utility operation would not have earned enough to cover its
14 dividend payment in 2002.

15 In 2003 the power supply costs finally began to drop
16 leading to a rate decrease of 18 percent. However,
17 customer growth and reliability requirements continue to
18 drive the need for investment in transmission and
19 distribution infrastructure.

20 Q. What are the implications of the current
21 financial situation?

22 A. The Company needs to fund its operating and

1 maintenance programs at adequate levels and needs to make
2 additional investments in infrastructure to ensure
3 continued high quality and reliable service for our
4 customers. Looking forward, the capital expenditures are
5 expected to remain high for the foreseeable future.

6 The cash flow situation has been precarious over the
7 last several years. Utility earnings did not cover the
8 dividend payment in 2001 and would not have covered the
9 payment in 2002 except for the tax method change.

10 Q. Did Idaho Power's Board of Directors (the
11 Board) recently vote to reduce the common stock dividend?

12 A. Yes. The Board voted on September 18, 2003
13 to reduce the total common stock dividend payment for the
14 next quarter from \$17,815,652 to \$11,493,969, a reduction
15 of \$6,321,683. This resulted in a reduction in the
16 IDACORP, Inc. annual dividend from \$1.86 per share to \$1.20
17 per share.

18 Q. Why did the Board take this action?

19 A. Idaho Power needs to strengthen its overall
20 financial position so that it will be able to fund Idaho
21 Power's \$675 million, three-year capital expenditure
22 program for the years 2004 through 2006. Reducing the

1 dividend will improve cash flow and help maintain a strong
2 credit rating while balancing the level of borrowing
3 necessary to meet the growing capital requirements.

4 Q. How does the \$675 million of estimated
5 capital expenditures over the next three years compare with
6 the capital expenditures for the most recent three years?

7 A. The Company's capital expenditures for the
8 years 2001 through 2003 are expected to total \$427 million.
9 The forecasted growth of \$675 million is a 58 percent
10 increase. I had Exhibit No. 4 prepared to show the
11 Company's actual/estimated capital expenditures for 2001
12 through 2006. Actual values have been included through
13 July of 2003.

14 Q. How does the Board's decision relate to the
15 Company's request for rate relief?

16 A. The Board recognized the need to generate
17 more cash to invest in the utility infrastructure and
18 strengthen the balance sheet. Accordingly, the Board
19 decided to pay the owners less through the common stock
20 dividend. In a similar fashion, timely rate relief also
21 strongly supports increased cash flow and a stronger
22 balance sheet with its corresponding enhanced credit

1 worthiness.

2 Q. As president of Idaho Power, where is your
3 focus?

4 A. My focus is the full restoration of Idaho
5 Power as a preeminent fully integrated utility with the
6 financial viability to successfully meet our customers'
7 needs both now and in the future.

8 Q. What progress have you made?

9 A. In my view, we have made remarkable
10 progress, particularly considering what we have been
11 through in recent years. The Company has managed through
12 the energy crisis and ongoing prolonged drought, taken
13 steps to meet our customers' needs and reduce risks to them
14 going forward, and made difficult decisions to maintain
15 credit quality and financial flexibility. Running an
16 efficient, quality utility is our priority and, as detailed
17 in Ms. Fullen's testimony, customers are recognizing our
18 efforts. I also believe that we have made some strides in
19 the area of demand-side management (DSM). Ms. Fullen's
20 testimony notes our senior management support in the DSM
21 area. I affirm her testimony.

22 Q. What is your opinion of the Company's rate

